U.S. Environmental Protection Agency
Applicability Determination Index

Control Number: M990003

Category: MACT
EPA Office: Region 6
Date: 12/04/1998
Title: Refinery Fuel Gas Defined
Recipient: Andes, Ronald
Author: Hepola, John

Subparts: Part 63, CC, Petroleum Refineries

References: 63.641

Abstract:

Q: What are the criteria for defining refinery process gas as refinery "fuel gas," considering that the promulgation of the refinery MACT standard, NESHAP Subpart CC, has resulted in combustion of process gases to control HAPs in combustion devices outside of the existing fuel gas system.

A: To be defined as NSPS Subpart J "fuel gas," the refinery process gas has to meet only two criteria: 1) the gas has to be generated at a petroleum refinery, and 2) the gas has to be combusted. There are no other criteria stated in Subpart J by which "fuel gas" is defined. Only two types of refinery vent streams are specifically exempt in Subpart J from the "fuel gas" definition.

Letter:

December 4, 1998

Mr. Ronald L. Andes Attorney
Marathon Ashland Petroleum LLC
539 South Main Street
Findlay, OH 45840-3295

Re: Petroleum Refinery - New Source Performance Standards (NSPS) Applicability Questions, dated February 26, 1998, and June 23, 1998 NSPS Part 60, Subpart J

Dear Mr. Andes:

The following is in response to your letter, dated February 26, 1998, to Jon York of my staff concerning clarification of the definition of "fuel gas," as the term is used in NSPS 40 CFR Part 60, Subpart J and associated applicability determinations, including the effect on the determinations of the Modification exemption at NSPS 40 CFR Part 60, Subpart A, 60.14(e)(5).

We also are responding to your letter, dated June 23, 1998, to me concerning applicability of NSPS Part 60, Subpart J to a storage vessel's proposed closed vent system and its proposed tank vapor emission control device, a flare. I understand that Marathon Ashland is considering a pollution reduction project to collect and convey existing petroleum storage tank emissions to a flare, which would be constructed and placed in operation to control the storage vessel emissions. You indicate in your letter that you need a determination of applicability of NSPS Part 60, Subpart J to the proposed system. You also offered the opinion that emissions from the storage tank do not meet the definition of "fuel gas," as the term is defined at Subpart J of 40 C.F.R. Part 60.

By copy of this letter, we are also responding to a letter, dated May 22, 1998, from John Hall, consultant concerning the same issues that you have raised. Mr. Hall wants a clarification of whether or not vapors produced from fuel loading operations are defined as "fuel gas" under NSPS Subpart J. Additionally, Mr. Hall wants to know if NSPS Subpart J could apply to vapor combustion devices that control vapors produced from fuel loading operations.

I understand that Marathon Ashland is concerned about NSPS Subpart J applicability issues addressed in the letter from Texas Natural Resources Conservation Commission (TNRCC), dated May 20, 1997, and an EPA confirmation letter, dated June 16, 1997, written in response to a request from Mr. Bharat Contractor of Woodward-Clyde, a consulting firm in Houston, Texas. In his letter, dated April 25, 1997, Mr. Contractor requested a NSPS Part 60, Subpart J "fuel gas" definition clarification from TNRCC, Louisiana Department of Environmental Quality (LDEQ), and EPA Region 6. I understand that Mr. Contractor was seeking the "fuel gas" clarification so that NSPS Subpart J applicability determinations for "fuel gas combustion devices" (FGCDs), as the term is defined in Subpart J, could be made with consistency from refinery to refinery.

I understand that Mr. Contractor's request letter resulted from the requirement in NESHAP 40 CFR Part 63, Subpart CC, the first petroleum refinery MACT standard, to control the "hazardous air pollutants" (HAPs) emitted from "miscellaneous process vents" at refinery process units. If certain "miscellaneous process vents," which were not required before promulgation of NESHAP Subpart CC to be controlled, were then routed to discharge into the already existing refinery fuel gas system due to EPA's promulgation of the petroleum refinery MACT standard at NESHAP Subpart CC, then these "miscellaneous process vents" are exempt from control of HAPs (see NESHAP Part 63, Subpart CC, 63.641, Definitions). The exemption of "miscellaneous process vents" from NESHAP Subpart CC HAP control requirements is included within the definition of a "miscellaneous process vent" in 63.641.

If the "miscellaneous process vents" are routed to discharge into the existing refinery fuel gas system, then a NSPS 40 CFR Part 60, Subpart J applicability determination, which would consist of both a Modification (see NSPS Part 60, Subpart A, 60.14) and a Reconstruction (see NSPS Part 60, Subpart A, 60.15) evaluation, would be needed. Mr. Contractor's letter did not request clarification of NSPS Subpart J applicability criteria for this situation. Instead, Mr. Contractor's letter requested a NSPS Subpart J applicability criteria clarification in the event that the NESHAP Subpart CC applicable refinery elects to route certain "miscellaneous process vents" to boilers, process heaters, and flares, outside of the refinery fuel gas system, for the purpose of destroying organic HAPs. Note that any refinery boiler, process heater, or flare constructed, modified, or reconstructed after June 11, 1973, is potentially subject to NSPS Subpart J as a "fuel gas combustion device" (FGCD).

On May 20, 1997, the Texas Natural Resource Conservation Commission (TNRCC) replied to the issues Mr. Contractor raised in his request. We understand that TNRCC responded to all of the NSPS Subpart J issues raised by Mr. Contractor. We mention this because we believe that responses given in TNRCC's letter relate to the issues that you are raising.

The last issue covered by Mr. Contractor in his letter concerns the connection of refinery process unit vent streams to boilers, process heaters, or flares for the purpose of destruction of organic HAPs found in the vent streams. Under NSPS Subpart J, a boiler, process heater, or flare could become a "fuel gas combustion device," if the connection meets the applicability criteria of NSPS Subparts A and J. This connection would be a physical or operational change to existing facilities, which would trigger the need for the owner or operator to undertake a Modification and a Reconstruction evaluation of the change. In the event that NSPS Subpart J would become applicable, the new off-gas control system would become a new NSPS Subpart J affected facility and Subpart J's monitoring, testing, recordkeeping, and reporting requirements would have to be met.

TNRCC touched on this issue near the end of its letter, dated May 20, 1997:

"Section 60.14(a) explains that except as provided in Sections 60.14(e) or (f), any physical or operational change which results in an increase in the emission rate of a regulated pollutant to the atmosphere is a modification. Therefore, if the addition of a new fuel gas stream to an existing boiler/heater/flare causes increased emissions, which is likely, that combustion device has been modified, and is subject to all applicable Subpart J emissions standards, recordkeeping, and reporting requirements, unless the addition of this new fuel gas stream can be exempted under one of the provisions of Section 60.14(e)."

On June 16, 1997, EPA Region 6 sent a letter to Mr. Contractor agreeing with TNRCC's May 20, 1997 letter.

The Louisiana Department of Environmental Quality (LDEQ) also responded to Mr. Contractor in a letter dated October 24, 1997. We believe that LDEQ essentially agreed with TNRCC's conclusion that each of the off-gas types listed in Mr. Contractor's letter would be classified as "fuel gas" if each is combusted in a a "fuel gas combustion device."

In your request letter, you noted that EPA had clarified the definition of "fuel gas" in the preamble of the Federal Register publication dated March 12, 1979. We understand that you offered the suitability of using amine treatment technology to remove H_2S from the off-gas as a means of defining what is and what is not "fuel gas." You claimed that EPA had established a "technology limit (amine treatment)" in the 1979 FR for defining the "applicability of a process gas to the definition of a fuel gas." You also claimed, using the 1979 FR publication, that "if a process vent stream identified in the TNRCC letter can't be amine treated, then the process vent gas stream is not a "fuel gas" under Subpart J." We believe that you are not considering all of the points in the 1979 FR publication that are relevant to the objective of that publication and that you have drawn too general a conclusion from it.

In the context of defining two types of refinery gas streams as not being refinery fuel gas in the 1979 FR publication, EPA listed suitability of amine treatment as one of the determining factors. EPA has defined the following substances as not being refinery fuel gas:

Gases generated by catalytic cracking unit catalyst regenerators.

Gases generated by fluid coking burners.

However, EPA used more than the suitability of amine treatment in making this determination.

The exemption of these two types of refinery process gases from being defined as refinery "fuel gas" was done in a NSPS Subpart J amendment on March 12, 1979, (see 44 FR 13480, dated 3/12/79). The rationale given by EPA for exempting these gases from the refinery "fuel gas" definition is based on the characteristics of the gases coming from the referenced refinery processes and the method of removal of Hydrogen Sulfide:

They are composed primarily of Nitrogen, Carbon Monoxide, Carbon Dioxide, and water vapor.

They contain small amounts of Hydrogen Sulfide. Note that the term "small amounts" is not defined in the Federal Register amendment.

The presence of Carbon Dioxide effectively precludes the use of amine treating as the means of Hydrogen Sulfide removal.

Amine treating of refinery process gas to remove Hydrogen Sulfide prior to combustion in refinery FGCDs is the primary control mechanism for NSPS Part 60, Subpart J to reduce Sulfur Dioxide emissions to the atmosphere from petroleum refineries.

EPA used, in 1979, all of the characteristics of the gases listed above to determine the subject exemption, not just one of them. However, EPA considered the above referenced characteristics of only the two above referenced gas stream sources for the purpose of defining NSPS Part 60, Subpart J applicability for those referenced refinery gas streams in 1979 and no other gas stream sources were considered. Furthermore, the two exempted gas streams were evaluated on only an individual basis and were not evaluated as mixtures of these gases with other refinery gases. Additional background information on the history of the definition of refinery "fuel gas" is given in the Enclosure.

In your letter dated February 26, 1998, you gave an example of an off-gas that you believe should not be required to be monitored with a NSPS Subpart J Hydrogen Sulfide (H_2S) continuous emission monitoring system (CEMS) the process vent stream from a refinery's Hydrogen plant. You indicated that natural gas is the feedstock for the Hydrogen plant and implied that it is as Sulfur free as "pipeline quality" natural gas. You also indicated that the hydrogen plant vent gases are not amine treatable.

We agree that the primary feedstock for the Hydrogen plant (natural gas) should be essentially Sulfur free, due to the need to protect the catalyst material in catalytic reformers from impairment by any Sulfur bearing compounds that may be present in the reformer's feedstock. The refinery's hydro-desulfurization unit should reduce feedstock Sulfur content to a very low level. We also agree that a Hydrogen plant vent stream would be less suitable for amine treatment to remove H_2S; the Carbon Dioxide (CO_2) content would interfere with the amine stripping process. However, we also believe that the applicability criteria of NSPS Subpart J, as is stated in the Code of Federal Regulations (CFR), does not support an automatic exemption from applicability of NSPS Subpart J requirements to this type of vent stream.

Even though you believe that a Hydrogen plant off-gas stream is an example of a vent stream that, if controlled by a flare to reduce HAP emissions by itself, should not be subject to NSPS Subpart J, you indicate that any vent stream that is not amenable to amine treatment should not be subject to NSPS Subpart J. You also indicate that the connection of a process unit's vent stream to a flare, process heater, or boiler for the purpose of controlling HAP emissions under NESHAP Subpart CC is the only "primary function" of the physical or operational change, thereby making every change of this type exempt from NSPS Subpart J applicability due to NSPS Subpart A, 60.14(e)(5).

The applicability criteria of NSPS Subpart J for fuel gas combustion devices (FGCDs) can be found in the definitions of "fuel gas" and "fuel gas combustion device" stated in Subpart J, 60.101, in addition to the criteria stated in 60.100:

"Fuel gas" means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners." (see 40 C.F.R. Part 60, Subpart J, 60.101, dated 7-1-97)

"Fuel gas combustion device" means any equipment, such as process heaters, boilers, and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid." (see 40 C.F.R. Part 60, Subpart J, 60.101, dated 7-1-97)

An examination of these definitions and the remainder of Subpart J results in the following conclusions:

1) There is no cut-off level in NSPS Subpart J, including the wording in the definition of "fuel gas," for refinery off-gas H_2S content below which NSPS Subpart J is not applicable.

2) The degree to which the refinery off-gas is amenable to amine treatment is not in the NSPS Subpart J applicability criteria.

3) Only two types of refinery vent streams are identified by definition as being automatically exempt from the label "fuel gas." They are gases generated by catalytic cracking unit catalyst regenerators and gases generated by fluid coking burners.

To be classified as refinery fuel gas, the refinery off-gas has to be:

Gas generated at a petroleum refinery. Note that this does not mean that the off-gas has to come directly from a refinery process unit. The off-gas can come from any source of waste gas in the refinery, including but not limited to, storage vessels or loading racks, as long as the gas was generated in the refinery.

Gas which is combusted. If the gas is returned to refinery operations without being combusted, it can not be refinery "fuel gas."

Any refinery off-gas that meets the above listed defining criteria will be classified as refinery fuel gas. Degree of amine treatability and amount of H_2S content are not to be used in the definition of refinery "fuel gas."

You also addressed the Modification issue that was initially touched on by TNRCC on May 20, 1997, and then was listed as an issue by LDEQ on October 24, 1997. We understand that you are addressing the situation in which the combustion device for the refinery off-gas, such as a flare, is an existing source before the refinery process unit vent is connected. Upon connection of the refinery process unit vent or vents to the combustion device, the applicability of NSPS Part 60, Subpart J should be evaluated on a case-by-case basis using all of the applicability criteria in NSPS Part 60, Subpart A, 60.14 (Modification) and 60.15 (Reconstruction).

We have discussed the issue of the NSPS Subpart J and A applicability criteria issues for refinery fuel gas systems and fuel gas combustion devices with EPA's Office of Air Quality Planning and Standards (OAQPS) at Research Triangle Park, North Carolina and EPA's Office of Enforcement and Compliance Assurance (OECA) at Washington, D.C. Our discussions indicate that this situation has been raised to a national level and that a response from EPA Headquarters is appropriate. EPA Headquarters is currently preparing a national response on the very same issues that you and others have raised to EPA Region 6.

The national effort continues a Regional effort which began with a review of the NSPS Subpart J applicability criteria to determine what is currently available in the published rules. The results of that review are included in this letter. EPA Headquarters and Regional offices are working to identify possible combinations of components that a refinery might put together in combusting waste gas streams that would be combusted to comply with NESHAP Part 63, Subpart CC. EPA is also reviewing the characteristics of the new gas streams to be controlled under NESHAP Subpart CC to determine which ones could cause NSPS Subpart J to be applicable, assuming that all other NSPS Subpart J applicability criteria has been met. In the interim, EPA believes that low H_2S content refinery waste gas streams that are potentially subject to NSPS Part 60, Subpart J applicability could be monitored with an approved alternative monitoring system.

If either EPA or the State agency delegated the NSPS authority determines that a refinery process vent stream is subject to NSPS Subpart J, the owner or operator of that vent stream is required to comply with all applicable provisions of NSPS Subpart J and Subpart A. If the owner or operator of a NSPS Subpart J applicable vent stream has information and measurements to show that the H_2S content of the Subpart J applicable fuel gas system is always at a low level, such that the need for continuous monitoring is not appropriate for the subject fuel gas system, then the owner or operator can submit a written request for an alternative monitoring plan approval, in accordance with NSPS Part 60, Subpart A, 60.13(i), to EPA through the State agency delegated the NSPS authority.

Several of these alternative monitoring plans have been approved by EPA Regional offices, including EPA Region 6. These determinations can be found on EPA's Applicability Determination Index (ADI) by searching the NSPS Part 60, Subpart J area within the ADI. The ADI is located on the EPA Internet web site at:

http://www.epa.gov/ttn/uatw/eparules.html

- or -

http://es.epa.gov/oeca/eptdd/adi.html

The request for the alternative monitoring plan approval should include reasons why the subject fuel gas system never has a H_2S content above a certain low level. Measured data and the technical characteristics of the fuel gas and the fuel gas system should be provided. If low Sulfur content of refinery feedstocks is claimed, then data verifying this claim should be submitted. If the presence of Sulfur in the gas stream would interfere with and/or destroy certain refinery components, then a description of the components and an explanation of how this is prevented should be submitted. A proposed H_2S content sampling method and a method of certifying the test procedure should be included in the plan. The owner should propose a reasonable frequency of monitoring of the H_2S fuel gas content. The plan approval would be conditioned to read that, if the H_2S fuel gas content ever exceeded a certain level, then the owner or operator would be required to install and operate a H_2S continuous emission monitoring system (CEMS), in accordance with NSPS Subpart J and Subpart A. If approved, the alternative monitoring plan would avoid the higher cost of a H_2S CEMS, unless applicable conditions of approval are not met.

This determination review was coordinated with appropriate staff at EPA's Office of Air Quality Planning and Standards (OAQPS) at Research Triangle Park, North Carolina and EPA's Office of Enforcement and Compliance Assurance (OECA) at Washington, D.C. If you have any questions regarding this determination, please contact Jon York of my staff at (214) 665-7289.

Sincerely yours,

John R. Hepola
Chief
Air/Toxics and Inspection
Coordination Branch

cc: James Wilkins (Marathon Ashland)
John Hall (consultant)
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Enclosure

History of the Definition of Refinery "Fuel Gas"

In defining what is and is not refinery "fuel gas," EPA has responded to several requests concerning several substances:

Propane fits the Subpart J definition of a fuel gas. (Applicability Determination Index (ADI) memorandum, Control No. J005, dated 3/22/77).

Ethylene fits the Subpart J definition of a fuel gas. (ADI memorandum, Control No. J007, dated 6/29/77).

Liquefied petroleum gas (LPG), which includes butane and propane, fits the Subpart J definition of a fuel gas. (ADI memorandum, Control No. J013, dated 9/26/78).

Naturally produced natural gas (from geological formations) does not fit the Subpart J definition of a fuel gas. Refinery produced natural gas (from refinery process units) fits the Subpart J definition of a fuel gas. (Determination memorandum, Control No. J012, dated 10/03/78). This distinction was proposed as a clarifying amendment to NSPS Subpart J on March 3, 1980, (see 45 FR 13991, dated 3/03/80). This amendment was finalized on December 1, 1980, (see 45 FR 79452, dated 12/01/80).

A flare is a NSPS Subpart J "fuel gas combustion device" (FGCD) at a petroleum refinery. A flare is one of the types of control devices that could be selected to control loading rack gas (vapor) that is liberated from liquids in loading rack equipment located in a bulk loading terminal at a refinery. Loading rack flares do combust fuel gas which is generated at a petroleum refinery. Therefore, loading rack gas (vapor) fits the Subpart J definition of a fuel gas. (ADI letter, Control No. PS26, dated 9/14/92).